Exhibit

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APPENDIX H – ENVIRONMENTAL REGULATIONS REVIEW

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I. GREENHOUSE GASES

A. Regulation of CO_2 from Existing Power Plants

1. *Clean Power Plan*

The U.S. Environmental Protection Agency (EPA) in October 2015 promulgated, under Section 111(d) of the Clean Air Act, a final rule *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, termed the "Clean Power Plan" (CPP).[1] At the time of our last Upper Midwest Resource Plan, the rule was final and some of our states were beginning to develop implementation plans. We discussed in that Plan how the expected CO_2 reductions under our Preferred Plan would position Xcel Energy for compliance with the CPP, under various assumptions about how our states might design their plans and allocate CO_2 allowances.

Several states and industry petitioners, led by West Virginia, filed suit at the D.C. Circuit Court to stay the CPP. The D.C. Circuit initially declined to stay the rule, but the U.S. Supreme Court stepped in and stayed implementation of the CPP in February 2016. In the interim, the D.C. Circuit Court has held the case in abeyance.

EPA estimated that at the national level, the CPP would have reduced electric sector CO_2 emissions by about 32% below 2005 levels by 2030. Xcel Energy has already exceeded this reduction, achieving approximately 34% below 2005 levels as of 2018 for our Upper Midwest system. Our Preferred Plan would take us beyond 80% below 2005 levels by 2030.

2. *Affordable Clean Energy rule*

EPA in October 2017 issued a proposed rule to repeal the CPP, based on its view that the CPP exceeds the EPA's statutory authority under the Clean Air Act.[2] EPA also published an Advanced Notice of Proposed Rulemaking seeking comment on whether to develop a replacement rule, and what form such a rule should take.[3] In August 2018, EPA then issued a proposed CPP replacement rule, *Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units*, termed the "Affordable Clean Energy" (ACE) rule.[4] The proposed rule applies to coal-fired steam electricity generating units in operation on or before January 8, 2014.

[1] 80 *Fed. Reg.* 64,662, October 23, 2015.
[2] 82 *Fed. Reg.* 48,035, October 16, 2017.
[3] 82 *Fed. Reg.* 61,507, December 28, 2017.
[4] 83 *Fed. Reg.* 44,746, August 31, 2018.

Whereas the CPP defined the Best System of Emission Reduction (BSER) to encompass CO_2 reductions achievable throughout the electricity system – including efficiency improvements at coal units themselves, switching from coal to gas, and renewable energy additions – the ACE proposal replaced this interpretation with a much narrower "inside the fence line" approach based only on heat rate improvements (HRI) implemented at the affected coal units. The proposal would require states to make unit-specific determinations of the achievable emissions reductions through HRI, expressed as an allowable emissions rate (lbs CO_2/MWh gross), and to evaluate eight "candidate technologies" for HRI: neural network/intelligent sootblowers, boiler feed pumps, air heater and duct leakage control, variable frequency drives, blade path upgrades for steam turbines, redesign/replace economizer, and improved operating and maintenance practices. EPA did not propose any BSER for existing natural gas-fired turbines, finding that available emissions reductions would be expensive or would likely provide only small reductions.

The proposed rule gives states limited flexibility in making these determinations. They may consider remaining useful life of a unit, which may result in the application of a less stringent standard of performance or later compliance date; may accept non-BSER measures, but only if implemented at the unit itself; and may allow averaging among units at a single power plant, but not across plants. States would not be allowed to average or trade across affected units, nor between affected units and non-affected sources such as wind or solar generation. As such, the proposed rule would not allow consideration of emission reductions achievable through measures such as renewable energy, energy efficiency, increasing natural gas generation, retiring or reducing operation of coal units.

3. *Affordable Clean Energy Rule as Finalized*

On June 19, 2019, EPA published a final ACE rule. Because of its release so near the filing of this Resource Plan, we are still reviewing the rule and, to the extent there are substantive differences between the proposed and final rule that impact our Preferred Plan, we offer to supplement the record. However, we include a preliminary review here.

The ACE rule finalizes EPA's repeal of the CPP, which EPA maintains exceeded EPA's statutory authority because EPA took an overly expansive view of section 111(d) and endeavored to reduce emissions by shifting the balance of coal, gas and renewable generation across the power grid rather than focusing only on measures implemented at the affected coal units.[5]

As in the proposed rule, EPA defines the BSER as only including measures implemented at the affected coal-fired units. The rule does not allow state plans to set carbon reduction targets based on renewable energy development, shifting from coal to gas, or averaging or trading across units – strategies the CPP relied on to drive the bulk of its emission reductions – but rather maintains the list of eight approved HRI measures states may consider in establishing unit-specific performance standards. It grants states discretion to determine which of those projects to require at the affected units and, following the statutory text, allows states to take into account the remaining useful life of the source and other factors, including the cost reasonableness of requiring HRI on units with a limited remaining useful life.

The final rule allows states three years from the date that it is published in the Federal Register to finalize plans and submit their own implementing rules. Compliance is then required two years thereafter, although states have discretion to extend that compliance deadline based on specific factors at the regulated units. Based on this timeline, we believe compliance could be required around 2024, not including possible delays due to litigation of the final rule.

4. *Relevance to Xcel Energy*

Xcel Energy submitted comments on the proposed ACE rule, arguing the Clean Air Act allows EPA to provide states much greater flexibility to reduce CO_2 through a range of actions throughout the electric system, and that granting such flexibility would result in more cost-effective and greater CO_2 reductions. However EPA retained its narrow, "inside the fence line" approach.

Under the rule as finalized – and absent our plans for early retirement of all remaining Upper Midwest coal units under the last Resource Plan and the current Preferred Plan – we expect that HRI could be required on coal-fired units that continue to operate. However, section 111(d)(1) explicitly requires, and EPA emphasizes, that EPA must "permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies."[6] Further, the proposed rule specifies that consideration of remaining useful life would allow a state's plan to establish tailored compliance deadlines specific to each source; consider "changes in the operation of the units, among other factors the state believes

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[5] EPA Fact Sheet, *Repeal of the Clean Power Plan*. June 19, 2019.
[6] ACE rule, 83 Fed. Reg. 44,749 (August 31, 2018).

are relevant";[7] consider "unreasonable cost of control resulting from plant age"; consider factors that "make application of a less stringent standard or final compliance time significantly more reasonable"; and consider "factors that influence decisions to invest in technologies to meet a potential performance standard [including] timing considerations like expected life of the source, payback period for investments, the timing of regulatory requirements, and other unit-specific criteria."[8]

The final rule also emphasizes this discretion:

> It will be up to the states to, either directly or indirectly, take cost into consideration in establishing unit-specific standards of performance. CAA section 111(d) explicitly allows the states to take into consideration, among other factors, the remaining useful life of the existing source in applying the standard of performance. For example, a state may find that an HRI technology is applicable for an affected coal-fired EGU but find that the costs are not reasonable when consideration is given to the timeframe for the planned retirement of the source (i.e., the source's remaining useful life).[9]

At this point, it is too early to predict exactly how Minnesota's ACE plan[10] will treat the units that the company is proposing to retire in our Preferred Plan. Minnesota's implementation of the ACE rule will depend on the outcome of inevitable litigation over the rule as well as the state plan development process, which will be in the hands of the Pollution Control Agency (PCA). Based on the factors set forth above, however, we believe that PCA could avoid requiring the installation of HRI on the company's coal units by incorporating the proposed unit retirement dates into the Minnesota ACE plan. Requiring HRI on units with only a few years of life remaining would necessitate a very short payback period, imposing accelerated depreciation of HRI investments and an unreasonable cost of control. We believe that, following the statutory language of Section 111(d)(1), EPA would be likely to approve such a plan. The company will continue to evaluate the implications of the ACE rule and work with PCA to harmonize the Minnesota ACE plan with the Preferred Plan in a manner that minimizes the cost of the ACE rule to customers.

B. Regulation of CO_2 from New, Modified and Reconstructed Power Plants

1. *Standards of Performance for New, Modified and Reconstructed Stationary Sources*

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[7] 83 Fed. Reg. 44,763.
[8] 83 Fed. Reg. 44,766.
[9] EPA "Affordable Clean Energy" final rule, pre-publication version, at page 81. *Repeal of the Clean Power Plan; Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units; Revisions to Emission Guidelines Implementing Regulations*. June 19, 2019.
[10] We do not speak to ACE plans in the other Upper Midwest states served by Xcel Energy, since the Company has no coal units in North Dakota, South Dakota, Wisconsin or Michigan.

EPA in October 2015 promulgated, under Section 111(b) of the Clean Air Act, a final rule *Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units.*[11] The rule applies to newly constructed, modified, and reconstructed fossil fuel-fired utility boilers and IGCC units, and newly constructed and reconstructed stationary combustion turbines. The trigger for applicability is that construction of the new unit began, or the modification or reconstruction took place, after January 2014. EPA defined the BSER for new fossil fuel-fired utility boilers as highly efficient supercritical pulverized coal with partial post-combustion carbon capture and storage (CCS), with an equivalent performance standard of 1,400 lbs CO_2/MWh gross. The BSER for natural gas-fired stationary combustion turbines operated in a "baseload" configuration is defined as use of efficient natural gas combined cycle technology, with a corresponding performance standard of 1,000 lbs CO_2/MWh gross, while natural gas-fired units (generally simple cycles) operated in a "non-baseload" configuration are given a performance standard of 120 lbs CO_2/MMBtu. Modified and reconstructed units in each category are given their own BSER definitions and corresponding performance standards.[12]

Numerous parties challenged the 2015 rule in the U.S. Court of Appeals for the D.C. Circuit, with the cases consolidated under *North Dakota v. EPA*. At EPA's request, the D.C. Circuit has held the consolidated cases in abeyance since April 2017, pending the Agency's review of the 2015 rule and any resulting rulemaking.

2. *Proposed 2018 Replacement Rule*

EPA in December 2018 released a proposed rule revising the 2015 section 111(b) rule discussed above. This rule, titled *Review of Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units*,[13] revises the emissions standards for new, modified, and reconstructed fossil fuel-fired electric utility steam generating units. EPA proposes that BSER would not be partial CCS, based on EPA's updated assessment of capital costs of CCS, falling electricity demand, water availability, and limited geographic availability of sites suitable for sequestration. Instead, EPA proposes that BSER is the most efficient demonstrated steam cycle (e.g., supercritical steam conditions for large units, subcritical steam conditions for small units) in combination with best operating

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[11] 80 *Fed. Reg.* 64,510, October 23, 2015.
[12] M.J. Bradley & Associates, August 14, 2015, *Summary of EPA's Final Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units*. Available at https://www.mjbradley.com/sites/default/files/MJB&A%20Summary%20of%20Final%20GHG%20NSPS_Aug14.pdf
[13] 83 *Fed. Reg.* 65,424, December 20, 2018.

practices. EPA proposes a corresponding set of emission standards, ranging from 1,900 lbs CO_2/MWh gross for units with heat input >2,000 MMBtu/hr, to 2,000 lbs CO_2/MWh gross for units with heat input <2,000 MMBtu/hr, to 2,200 lbs CO_2/MWh gross for various other types of units and for modified and reconstructed units.

EPA does not propose revisions to the 2015 rule for stationary combustion turbines. EPA does solicit comment on whether the rule should make allowances for circumstances in which simple-cycle stationary combustion turbines may be called upon to operate in excess of the "non-baseload" threshold in the 2015 rule, e.g. due to high utilization to balance solar and wind generation, and whether such turbines should be given a separate subcategory and standard of performance.

Finally, EPA proposes to retain its original "endangerment" finding as the basis for regulating CO_2 emissions from fossil fuel-fired EGUs, but takes comment on whether it is correct to interpret this finding as a finding made only once for each source category, or whether EPA must make a new endangerment finding each time it regulates an additional pollutant by an already-listed source category. EPA also solicits comment on whether there is a rational basis for declining to regulate CO_2 emissions from new coal-fired units in light of ongoing and projected reductions in power sector CO_2 emissions. The 111(b) revision remains a proposed rule as of this writing.

3. Relevance to Xcel Energy

Xcel Energy commented on the 2015 rule, indicating we did not agree CCS is an appropriate BSER because it was not adequately demonstrated and was not at the time deployed on any commercially operating power plant in the United States. Since that time CCS has been deployed on a small number of commercial units, but remains far from widespread. We believe CCS on *gas* units may become viable in the future, and is one of several potential carbon-free dispatchable technologies that could help achieve our 2050 aspiration of 100% carbon-free electricity. However, Xcel Energy does not have plans to build a new coal-fired power plant, with or without CCS, so the rule's requirements for new coal units have no impact on the Company.

We believe any new natural gas combined cycle unit we may construct would be able to meet the 2015 rule's performance standard of 1,000 lbs CO_2/MWh gross. It is possible that new simple-cycle stationary combustion turbines we build[14] could be called upon to operate in excess of the non-baseload thresholds in the 2015 rule, and

[14] Note that under the Preferred Plan, our modeling calls for no new gas combustion turbines until 2031, and even at that time, gas combustion turbines could be replaced by other resources that meet the same firm peaking need.

could struggle to achieve the 120 lbs CO_2/MMBtu performance standard applicable to such units. Since these units would likely operate this much only because they are supporting integration of higher amounts of renewables, we believe it may be appropriate for EPA to relax the non-baseload threshold or create a separate subcategory and standard of performance for such units. EPA's decision on simple-cycle aeroderivative turbines will become known when EPA finalizes the 111(b) rule.

C. Progress on the State of Minnesota's Greenhouse Gas Goals

The Next Generation Energy Act (NGEA) of 2007 states that:

> It is the goal of the state to reduce statewide greenhouse gas emissions across all sectors producing those emissions to a level at least 15 percent below 2005 levels by 2015, to a level at least 30 percent below 2005 levels by 2025, and to a level at least 80 percent below 2005 levels by 2050.[15]

These goals apply to all economic sectors; the NGEA does not provide goals specific to electricity or other sectors, or to individual companies. The Minnesota Pollution Control Agency (PCA) maintains the state's GHG inventory, publishes data,[16] and provides a biennial report to the Legislature on progress on the NGEA goals.[17]

1. *Xcel Energy's CO_2 Inventory and Reporting Methods*

Xcel Energy supports timely, transparent public reporting of CO_2 and other greenhouse gas emissions. Our comprehensive GHG reporting is based on The Climate Registry[18] and its *Electric Power Sector Protocol*, which aligns with the World Resources Institute and ISO 14000 series standards. Our company joined The Climate Registry as a founding member in 2007 to help establish a consistent and transparent standard for calculating, verifying and reporting greenhouse gases. Through The Climate Registry, we annually third-party verify, register and publicly disclose our greenhouse gas emissions. We have reported and verified emissions for 2005 through 2017, with verification of 2018 emissions pending. This reporting – which differs in a few respects from PCA's methodology for the state – takes the following approach:

- CO_2 emissions are reported from all owned power plants and purchased power across our Upper Midwest integrated system, serving five states. This is a broader boundary than PCA's method, which considers emissions from power plants within Minnesota and estimates emissions from power imported into

[15] Minn. Stat. §216H.02, subd. 1.
[16] See https://www.pca.state.mn.us/air/greenhouse-gas-emissions-data.
[17] See https://www.pca.state.mn.us/air/state-and-regional-initiatives.
[18] See https://www.theclimateregistry.org.

Minnesota.

- It includes CO_2 from owned fossil fuel-fired power plants, purchased power agreements (PPAs), and power purchased in the wholesale markets. The majority of these emissions (over 80 percent) are directly measured using Continuous Emissions Monitoring Systems (CEMS); a small portion (less than 10 percent) are from PPAs with counterparties whose emission rate is known because they report emissions to EPA, the Energy Information Administration or Federal Energy Regulatory Commission; a still smaller portion (less than 5 percent) are from counterparties who do not have a defined PPA with Xcel Energy and so are assigned a regional grid average emission rate.
- Reported emissions from power generation include CO_2 only, not methane and nitrous oxide. However, methane and nitrous oxide add less than ½ of one percent to our total CO_2-equivalent emissions, even after accounting for the greater global warming potentials of these gases.
- We report CO_2 from electricity provided to our customers. Xcel Energy sells a small portion of the electricity we generate and purchase as short-term sales into the wholesale market. CO_2 from these sales is excluded from our reporting, because the energy does not serve our customers, and it is likely that many companies purchasing the energy account for the emissions in their reporting, so including them in our reporting could result in double counting.

2. *State Goal for 2015*

PCA's statewide GHG inventory data now covers 2005 through 2016. Statewide GHG emissions declined about 5 percent from 2005 to 2015, missing the statewide goal of 15 percent. Statewide emissions declined more in 2016 – reaching 12 percent below 2005 by the end of that year – however performance varied by sector: electric sector emissions declined 29 percent, transportation emissions 8 percent, agriculture, forestry and land use emissions 12 percent, and waste emissions 6 percent, while emissions in the residential, commercial and industrial sectors all increased.[19]

Thus while the state overall and individual sectors have fallen short of the NGEA goals, the electric sector has approximately doubled the targeted reduction. According to PCA,

> Emissions from electricity used by Minnesotans are down by about 29% since 2005. This means the electricity generation sector has met the Act's 2015 goal, and has nearly

[19] See https://www.pca.state.mn.us/air/greenhouse-gas-emissions-data, as well as PCA's January 2019 report, *Greenhouse gas emissions in Minnesota: 1990-2016: Biennial report to the Legislature tracking the state's contribution to emissions contributing to climate change*, pages 5-6, available at https://www.pca.state.mn.us/sites/default/files/lraq-2sy19.pdf.

> reached the 2025 emissions reduction goal. Moreover, Minnesota's utilities have committed to additional coal plant closures that will further reduce GHG emissions from this sector in the future. Transportation is now the largest source of GHG emissions in Minnesota. This sector will require ongoing, focused effort to reduce emissions to the levels necessary to meet statutory goals.[20]

Xcel Energy's Upper Midwest CO_2 emissions have declined by even more. We provide below our emission reductions to date for three relevant years: 2015, for comparison to the NGEA goal for that year; 2016, for comparison to PCA's statewide data; and 2018, our latest emissions data available. Note that the 2018 data is not yet third-party verified.

Table 1: Xcel Energy Upper Midwest CO_2 Emission Reductions

Year	Total CO_2 from electricity serving customers (million short tons)	Reduction from 2005	Comparison
2015	21.1	25 percent	Exceeding state goal of 15 percent by 2015
2016	19.0	32 percent	More than double state goal for 2015 and exceeding state goal for 2025
2018	18.5	34 percent	More than double state goal for 2015 and exceeding state goal for 2025

3. State Goal for 2025

Under the Preferred Plan, Xcel Energy's Upper Midwest CO_2 emissions are on track for an approximately 60 percent reduction by 2025, doubling the NGEA statewide goal for that year. These reductions reflect our full 1,850 MW wind portfolio being online by that time, significant growth of solar, continued energy efficiency program achievements, continued operation of our carbon-free nuclear units, and retirement of one Sherco unit in 2023 (with the other two units at Sherco and the A.S. King unit retiring by 2030).

4. State goal for 2050

A true transformation has occurred in the electric sector since our last Resource Plan. In that plan, we discussed the state's 80 percent by 2050 goal qualitatively, but identified many technical and economic barriers to creating a Upper Midwest system that serves our customers' electricity needs affordably and reliably with only 20 percent of the CO_2 emissions of 2005. Today, only four years later, Xcel Energy has

[20] *Greenhouse gas emissions in Minnesota: 1990-2016*, page 2.

set a company-wide goal of an 80 percent reduction in CO_2 emissions *by 2030* – i.e. achieving the State's economy-wide goal, twenty years ahead of time. Moreover, we believe we can achieve this reduction cost-effectively, with our expected fleet transition and operational changes and with the renewable, carbon-free generation and energy storage technologies available today. Our 80 percent by 2030 goal is for all eight states Xcel Energy serves; under the Preferred Plan, our Upper Midwest system will achieve about an 84 percent reduction. And our aspiration for 2050 is 100 percent carbon-free electricity for our customers.

In announcing these goals, we stressed that they are not Resource Plans. Our Preferred Plan represents a concrete down payment on those Xcel Energy-wide goals – moving our Upper Midwest system beyond 80 percent reduction by 2030 and putting us on a trajectory to removing carbon from our customers' electricity entirely by 2050. We also made clear that our 2050 aspiration requires technologies not yet commercially available at the scale needed. This cannot be done with only wind, solar, and the short-duration battery storage technologies available today. It will likely require some amount of carbon-free dispatchable generation, longer-duration storage than is available today, more electrification, and more flexible demand. The technologies needed may include gas with carbon capture and storage, power to gas (renewable hydrogen), seasonal energy storage, advanced nuclear or small modular reactors, deep rock geothermal, and other technologies yet to be identified. Each of these options holds promise, but they will require further research, development, demonstration and deployment to become viable solutions at the cost and scale needed. Coupled with supportive federal and state policies, utility Resource Plans can send signals to the market around price, capabilities and timing for when these technologies will be needed.

In sum, we believe the state's goal of 80 percent reduction by 2050 is attainable and affordable within the electric sector, and that even 100 percent carbon-free electricity by 2050 is achievable with sufficient investment in new technology. That said, getting the last 20 percent of carbon out of the electric system is technically challenging and could face steeply increasing costs. This is especially the case if we limit the portfolio to two or three technologies – e.g., wind, solar and short-term storage – rather than creating a balanced portfolio of technologies for an affordable, reliable, and carbon-free system in 2050.

D. Recent Federal and State Legislation

No new state or federal legislation mandating a reduction in GHG emissions from Xcel Energy's system has passed as of filing this plan. However, some legislation has been proposed, which may indicate the potential shape of energy/climate policy in coming years. We summarize here some of those proposals.

1. Green New Deal

In February 2019, Rep. Ocasio-Cortez (D-NY) and Sen. Markey (D-MA) introduced H. Res. 109 and S. Res. 59, formalizing one version of the "Green New Deal" (GND) concept of an aggressive mobilization to address climate change combined with nationwide job creation, modeled on the Depression-era programs of the Roosevelt Administration. The resolutions cite recent United Nations and U.S. Government reports on climate risks and propose that, in order to keep global temperature increase below 1.5 degrees Celsius, GHG emissions must be reduced 40-60 percent by 2030 from 2010 levels and reach net-zero global emissions by 2050. The resolutions point to the impacts of climate change in exacerbating systemic injustices and disproportionately impacting certain vulnerable communities, as well as the threat posed to national security, and call for ambitious progressive policies aimed at resolving social injustice as part of the transition.

The resolutions propose it is the duty of the Federal Government to create a GND that would achieve net-zero GHG emissions through a fair and just transition for all communities and workers; create millions of good, high-wage jobs and ensure prosperity and economic security for all; invest in infrastructure and industry to sustainably meet the challenges of the 21st century; secure for future generations clean air and water, climate and community resiliency, healthy food, access to nature, and a sustainable environment; and promote justice and equity by stopping current, preventing future, and repairing historic oppression of indigenous peoples, communities of color, migrant communities, deindustrialized communities, depopulated rural communities, the poor, low-income workers, women, the elderly, the unhoused, people with disabilities, and youth.[21]

To achieve these goals, the resolutions call for a ten-year national mobilization focusing on 1) building resiliency against the impacts of climate change, such as extreme weather; 2) repairing and upgrading infrastructure; 3) meeting 100% of the power demand through clean, renewable, and zero-emission energy sources; 4) building or upgrading energy efficient distributed and "smart" power grids; 5) upgrading all existing buildings for maximum resource efficiency (energy, water) and safety, including through electrification; 6) spurring growth in clean manufacturing; 7) working with farmers and ranchers on sustainable farming and decarbonization of the agricultural sector; 8) development of zero-emission vehicle infrastructure and manufacturing and more public transit/rail; 9) funding for communities with

[21] See https://www.congress.gov/bill/116th-congress/house-resolution/109/text.

pollution related health problems; 10) removing GHG from the atmosphere through proven low-tech solutions such as land preservation and afforestation; 11) restoring threatened and endangered ecosystems; 12) cleaning up hazardous waste sites; 13) eliminating sources of pollution; and 14) promoting international exchange of technologies and expertise on climate.[22]

Notably different from earlier GND proposals, the resolutions do not call for 100 percent renewable energy, but instead a transition to clean, zero-carbon energy, leaving open possibilities non-renewable but zero-carbon sources. They do not call for a carbon price, since at least some of the groups supporting the GND do not favor a carbon tax or cap-and-trade.

Since these GND resolutions are high-level statements of goals and principles for federal programs, rather than specific compliance mandates for electric utilities, we cannot directly evaluate this Resource Plan in relation to them. We note that this Resource Plan appears generally consistent with the resolutions in that it would:

- Reduce Xcel Energy's Upper Midwest emissions 80 percent by 2030, as compared to the GND goal of 50-60 percent;
- Put Xcel Energy on a path to 100 percent carbon-free electricity for our customers by 2050, more ambitious than the GND net-zero goal;
- Prioritize a fair and just transition by working to create new jobs and economic opportunities in the communities hosting retiring power plants, while also creating new employment in building and operating clean energy resources added to our system;
- Focus on reducing conventional pollution and expanding clean energy access for all;
- Improve the resiliency of our electric system and communities;
- Upgrade energy infrastructure and invest in a smarter energy grid, energy efficiency, and electrification of transportation and other end uses.

2. *Clean Energy Standard Act of 2019*

Senators Tina Smith (D-MN) and Ben Ray Luján (D-NM) in May 2019 introduced S. 1359, the *Clean Energy Standard Act of 2019*. This bill, which the authors describe as a path to net-zero emissions in the electric sector by midcentury, would establish a federal clean energy standard (CES) requiring retail electric suppliers to provide an

[22] https://www.congress.gov/bill/116th-congress/house-resolution/109/text.

increasing share each year of the electricity serving their customers from "clean energy" resources, defined to include renewables, qualified renewable biomass, hydroelectricity, nuclear, qualified waste-to-energy, qualified low carbon fuels, qualified combined heat and power, qualified energy storage, dispatchable low- and zero-emission technologies, and carbon capture, storage and utilization. The approach is modeled on state renewable energy standards, but broader since in addition to renewables it allows low- and zero-carbon resources to qualify.

The bill requires retail electricity suppliers with more than 60 percent clean energy today to increase their clean energy percentage (as a share of retail sales plus behind the meter generation) at 1.75 percent per year, while retail electricity suppliers with less than 60 percent today must increase at 2.75 percent per year. Retail electricity suppliers comply with the CES by adding clean energy resources to their fleet, purchasing federal clean energy credits from other retail electricity suppliers, or paying an alternate compliance payment initially set at 3 cents per kWh. Recognizing the need for 24/7 low- and zero-carbon technologies in addition to variable renewables, the bill provides innovation multipliers for dispatchable low-emission and dispatchable zero-emission technologies. It also establishes a new clean energy research, development, demonstration and deployment program within the US Department of Energy.

We believe the Company is well positioned to comply with the CES as introduced. Under our Preferred Plan, the Company would have greater than 60 percent qualifying clean energy from 2019 on, so be required to increase at the slower 1.75 percent per year rate; by 2023, the Company's clean energy percentage would exceed the 90 percent ceiling at which retail electricity suppliers are no longer required to increase until 2040. Due to planned renewable additions, maintenance of our nuclear units, and the proposed relicensing of Monticello, our modeling shows the Company in excess of its compliance obligation throughout the planning period of 2020 to 2034.

3. *Walz/Flanagan Clean Energy Plan*

In March 2019 Minnesota Gov. Walz and Lt. Gov. Flanagan proposed a "One Minnesota Path to Clean Energy," a set of three policy proposals designed to achieve 100 percent clean energy in the state's electricity sector by 2050. The three components are:

- *100 Percent Clean Energy by 2050*. This standard would require all electric utilities in Minnesota to use only carbon-free energy resources by 2050, while allowing each utility the flexibility to choose how and at what pace they meet the standard. The proposal includes provisions to assist workers and communities affected by the transition, while prioritizing local jobs and prevailing wages for large new clean energy projects.

- *Clean Energy First*. This regulatory policy would require that, whenever a utility proposes to replace or add new power generation, it must prioritize energy efficiency and clean energy resources over fossil fuels. This policy would strengthen an existing renewable energy preference in Minnesota law, and it would allow for fossil fuel-based power only if needed to ensure reliable, affordable electricity.
- *Energy Optimization*. This proposal would raise Minnesota's Energy Efficiency Resource Standard for investor-owned electric utilities and expand the Conservation Improvement Program that helps Minnesota households and businesses save on their utility bills by using energy more efficiently. It would also encourage utilities to develop innovative new programs to help consumers and businesses switch to more efficient, cleaner energy. In addition, it would target more energy-saving assistance for low-income households."[23]

To carry out this proposal, the Administration worked with legislators to introduce HF1956, which included all three components above, and SF1456, which included only the Clean Energy First preference. The bills were incorporated into the respective House and Senate omnibus legislation. Ultimately, none of this package of bills passed the Minnesota Legislature in 2019, but they provide an indication of the potential direction of clean energy policy in Minnesota in the coming years. We believe the Preferred Plan positions the Company well to comply with these policies.

II. CONVENTIONAL POLLUTANTS

This section discusses requirements that may apply to emissions of pollutants that are regulated under four primary Clean Air Act (CAA) programs: National Ambient Air Quality Standards (NAAQS), a CAA program that addresses interstate transport of air pollution, CAA programs that address visibility impairment in national parks and wilderness areas, and a CAA program that addresses emissions of hazardous air pollutants. Each program is addressed in turn.

A. National Ambient Air Quality Standards

The CAA requires the EPA to set NAAQS to protect public health and the environment. NAAQS include both (1) primary standards to protect public health, including the health of sensitive populations, such as asthmatics, children and the

[23] See https://mn.gov/governor/news/?id=1055-374280.

elderly and (2) secondary standards to protect public welfare, including protection against damages to animals, crops and buildings. The EPA has established NAAQS for six pollutants: particulate matter (PM), nitrogen oxides (NO_x), sulfur dioxide (SO_2), ozone, carbon monoxide (CO), and lead (Pb). The NAAQS program has been in place since the early 1970s. The EPA is required to review the NAAQS every five years and revise them as appropriate to protect public health and welfare.

Once EPA adopts or revises a NAAQS, states have two years to monitor their air, analyze the data and submit to EPA their recommended classification of the state into Attainment areas (areas having monitored ambient air quality concentrations below the NAAQS), Nonattainment areas (areas having monitored ambient air quality concentrations above the NAAQS), and Unclassifiable areas. The EPA reviews the state's submittal and determines the final area designations a year later. When the EPA designates an area as Nonattainment, the state is given up to three years to develop a new State Implementation Plan (SIP) which identifies actions to be taken to bring the area back into Attainment. A SIP must include emission reduction requirements needed to demonstrate that air quality will attain the NAAQS in the timelines required by the CAA – usually within two to seven years after the SIP is submitted to the EPA for approval.

Recent revisions to all six NAAQS were finalized within the last few years to reflect the latest scientific information about the health effects of these air pollutants. Despite several NAAQS being significantly tightened, there are at present no Nonattainment areas in the state of Minnesota that might result in SIP emission reduction requirements being imposed on Xcel Energy's Upper Midwest power plants. The following table summarizes the current status of the NAAQS Attainment in Minnesota:

Table 2: Xcel Energy Upper Midwest System Status – NAAQS Attainment

Pollutant	Date Reviewed[24]	System Status[25]	Date Designated	Next Review[26]
PM	2012	Attainment	2015[27]	2020
O_3	2015	Attainment	2017[28]	2020
SO_2	2019	Attainment	2018[29]	2024
NO_x	2018	Attainment	2012[30]	2023
CO	2011	Attainment/Maintenance[31]		TBD[32]
Pb	2016	Attainment	2011[33]	2021

Our remaining coal plants are all equipped with scrubbers to control SO_2 emissions as well as air pollution control equipment to control PM emissions. All three Sherco units are equipped with NOx combustion controls that have significantly reduced NO_x emissions from the units. The King plant and our combined cycle gas plants are also equipped with Selective Catalytic Reduction (SCR) technology to control NO_x emissions.

With the planned retirement of Sherco Units 1 and 2, the only additional control equipment that could be required would be SCR technology to further reduce NO_x emissions from Sherco Unit 3. Depending on the date of required compliance, any need to install an SCR to address a NAAQS would either need to be completed by the attainment date or the unit would need to shut down by the attainment date. With the proposed 2030 retirement of Sherco 3, we believe unit retirement may be acceptable in lieu of SCR. Additionally, a full analysis may render the controls not cost-effective

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24 This column reflects the last time each NAAQS was reviewed. Note that in the case of the most recent reviews of the NAAQS for SO_2, NOx, CO and Pb, EPA did not change the level of the NAAQS, so there was no need to initiate a new designation and planning process for those standards.
25 This column reflects the designation of areas for locations where Xcel Energy's Upper Midwest coal or natural gas plants are located.
26 This column reflects the date of EPA's announced plans to review a NAAQS, application of the five year CAA deadline for NAAQS reviews, or "TBD" if the five year deadline has passed and there is no announced plan to complete the next NAAQS review.
27 *See* 80 Fed. Reg. 2206, 2247-48 (Jan. 15, 2015).
28 *See* 82 Fed. Reg. 54232, 54255-56 (Nov. 16, 2017).
29 *See* 83 Fed. Reg. 1098, 1134-36 (Jan. 9, 2018).
30 *See* 77 Fed. Reg. 9532, 9562 (Feb. 17, 2012).
31 As of 2010, there were no areas of the country in Nonattainment of the CO standard. Areas formerly Nonattainment have all been designated "maintenance" areas, which are subject to certain CAA requirements for two ten-year maintenance periods after achieving compliance with the standards to assure continued attainment. https://www.epa.gov/co-pollution/applying-or-implementing-outdoor-air-carbon-monoxide-co-standards#designations The Minneapolis/St. Paul Metropolitan Area is a maintenance area for CO. https://www3.epa.gov/airquality/greenbook/cbcs.html#MN
32 Because the last review in 2011 retained the original NAAQS adopted in 1971, we do not expect this standard to change in the future.
33 *See* 76 Fed. Reg. 72097, 72111 (Nov. 22, 2011), which designated all of Minnesota as attaining the standard, except a portion of Dakota County.

based on the reductions to be achieved.

In addition, if future further emission reductions are needed, it is possible that the state would evaluate whether any upgrades are available to existing controls to further reduce air emissions.[34] Based on the timeline for the next NAAQS reviews shown above, if a standard is made more stringent in the future, and if Minnesota does not meet that standard in areas where our plants operate, further emission reductions might be considered at Xcel Energy's Upper Midwest coal and natural gas plants in the mid to late 2020s.

B. Interstate Transport of Air Pollution

The CAA also requires that NAAQS SIPs include provisions that prevent sources within a state "from emitting any air pollutant in amounts which will … contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any" NAAQS.[35] The EPA has developed programs for the Eastern U.S. that would reduce interstate transport of pollutants emitted by Electric Generating Units (EGUs) that are precursors to ozone and fine particles. NO_x is a precursor to ozone and fine particle formation, while SO_2 is a precursor to fine particle formation.

The Cross-State Air Pollution Rule (CSAPR) was designed as a "cap-and-trade" program that reduces overall emissions from EGUs. This means that total emissions from EGUs in a state or region are limited (the cap), and each ton of emissions allowed is represented by an emission allowance that can be transferred among EGUs (the trade). A cap-and-trade program thus reduces total emissions to the capped amount, but provides flexibility for EGUs to meet their individual emission reduction requirements through installation of control equipment, purchase of emission allowances from other EGUs, or a combination of both.

Depending on EPA's analysis of an upwind state's contribution to Nonattainment in downwind states, CSAPR imposes one or both of the following emission limitations: (1) summer season NO_x emissions (to address ozone), and/or (2) annual NO_x and SO_2 emissions (to address fine particles). In Minnesota's case, the impact of concern has been fine particle Nonattainment areas in downwind states, rather than ozone. The CSAPR has applied since 2015 to Minnesota for fine particle precursors and to Wisconsin for fine particle precursors and ozone. NSP-Minnesota holds sufficient emission allowances to meet CSAPR requirements, while NSP-Wisconsin has

[34] In general, upgrades to existing pollution control technology are far less expensive than installation of an entirely new retrofit control system.
[35] CAA, 42 U.S.C. section 7410(a) (2)(D)(i)(I).

complied through operational changes and some allowance purchases.

EPA has considered further revisions to the CSAPR program as may be needed to address the 2008 ozone NAAQS and the 2012 particle NAAQS. EPA decided that further reductions through CSAPR are not needed to address the 2012 particle NAAQS,[36] and recently decided that further reductions from current emission levels are not needed to address the 2008 ozone NAAQS.[37] It is not known whether or when EPA might consider further emission reductions as part of implementing the 2015 ozone NAAQS.[38]

C. Visibility Impairment in National Parks and Wilderness Areas

Visibility impairment is caused when sunlight encounters pollution particles in the air. Some light is absorbed and other light is scattered before it reaches an observer, reducing the clarity and color of what the observer sees. The CAA established a national goal of remedying existing and preventing future visibility impairment from man-made air pollution in specified "Class I" areas – national parks and wilderness areas throughout the United States, including the Boundary Waters Canoe Area and Voyageurs National Park in Minnesota. The visibility programs focus on reducing emissions of PM, SO_2 and NO_x as pollutants that can result in visibility impairment from EGUs.

The EPA has taken a two-step approach to implement the visibility program. The first step, "reasonably attributable visibility impairment" (RAVI), was implemented in the 1980s to address visibility impairment reasonably attributable to a specific source. The EPA adopted regulations for this program designed to address RAVI, defined as "visibility impairment that is caused by the emission of air pollutants from one, or a small number of sources."[39]

The second step was designed to address widespread, regionally homogeneous haze

[36] On March 17, 2016, EPA issued guidance for states to analyze interstate pollution impacts and, if needed, to develop plans to address those impacts. EPA stated that few areas would have problems meeting the 2012 particle NAAQS, and plans to address any need for upwind reductions on a case-by-case basis. *Information on the Interstate Transport "Good Neighbor" Provision for the 2012 Fine Particulate Matter National Ambient Air Quality Standards under Clean Air Act Section 110(a)(2)(D)(i)(I),* Office of Air Quality Planning and Standards, at 3.

[37] *See* 83 Fed. Reg. 65878 (Dec. 21, 2018).

[38] On March 27, 2018, EPA issued guidance for states to design their own plans to address interstate air pollution impacts as part of their SIPs under the 2015 ozone NAAQS. https://www.epa.gov/airmarkets/memo-and-supplemental-information-regarding-interstate-transport-sips-2015-ozone-naaqs If in the future states submit plans that EPA does not approve on this issue, EPA could consider developing its own plan at some future date.

[39] 40 C.F.R. section 51.301. Following an allegation that the Sherco plant might have a RAVI-type of impact, NSP-Minnesota entered into a settlement agreement that agreed to tighten SO2 emission limits on all three Sherco units to resolve the allegation. The new limits have been implemented at the Sherco plant. *See* 40 C.F.R. section 52.1236(e), adopted on March 7, 2016 (81 Fed. Reg. 11668).

that results from emissions from a multitude of sources. In 1999, the EPA adopted its Regional Haze Rule (RHR) to address this type of visibility impairment. State environmental agencies are required to submit SIPs that develop and implement their strategy to reduce emissions that may contribute to regional haze. RHR SIPs also must include reasonable progress goals and periodic evaluation/revision cycles designed to make appropriate progress toward the national goal of no human-caused visibility impairment in Class I areas by 2064. These SIPs must be revised approximately every ten years to continue making reasonable progress toward reaching the 2064 national goal.

The Minnesota Pollution Control Agency (PCA) developed, and EPA approved, Minnesota's regional haze plan for EGUs for the first ten-year planning period of the program. The PCA's plan for Sherco Units 1 and 2 required combustion controls to reduce NO_x (Over-Fire Air (OFA), combustion controls and Low- NO_x burners) and scrubber upgrades to reduce SO_2. These controls have been installed and are in operation to reduce emissions from these units.

The PCA will also be required to revise its SIP by 2021 to consider additional emission reductions that may be necessary to continue to make reasonable progress during the next ten year planning period toward achievement of the national visibility goal by 2064.

Our system is equipped with almost all of the pollution control equipment that could be required in future regional haze planning cycles. With the planned retirement of Sherco Units 1 and 2, the only additional control equipment that could be required would be SCR technology to further reduce NOx emissions from Sherco Unit 3. Depending on the date of required compliance, any need to install an SCR to address Regional Haze compliance would depend on unit retirement dates. The Regional Haze program provides some flexibility to agree to a unit retirement some years later than an SCR might otherwise be required, because of the long-term nature of this program. With the proposed 2030 retirement of Sherco 3, we believe unit retirement may be acceptable in lieu of SCR. Additionally, a full analysis may render the controls not cost-effective based on the reductions to be achieved.

In addition, if future further emission reductions are needed, it is possible that the state would evaluate whether any upgrades are available to existing controls to further reduce air emissions. Our remaining coal plants all have scrubbers installed to control SO_2 emissions and have air pollution control equipment to control PM emissions. All three Sherco units are equipped with NO_x combustion controls that have significantly reduced NOx emissions from the units. The King plant and our combined cycle gas plants are also equipped with SCR technology to control NO_x emissions.

D. Regulation of Hazardous Air Pollutant Emissions

Both state and federal regulations require reductions in Hazardous Air Pollutant (HAP) emissions from power plants. In 2006, the Minnesota Legislature passed the Minnesota Mercury Emissions Reduction Act (MMERA). The MMERA provided a process for implementation and cost recovery for utility efforts to reduce mercury emissions at certain power plants, in our case the King and Sherco generating facilities. In 2012, the EPA adopted its final rule establishing National Emission Standards for HAPs from coal- and oil-fired power plants. This rule is often referred to as the Mercury and Air Toxics Standard (MATS), and compliance was required by 2015. Mercury controls have already been installed and are operational on all three Sherco units and at King.[40]

The MATS also set emission limits for acid gases and non-mercury metals. PM is a surrogate for non-mercury metal emissions and SO_2 is a surrogate for acid gas emissions. The Sherco and King plants meet these standards using control technologies and through operational practices.

In 2011, the EPA adopted emission limits for HAPs from industrial boilers to regulate boilers and process heaters fueled with coal, biomass and liquid fuels. These standards apply to biomass combustion at Bay Front Units 1 and 2 as well as to several small heating boilers located at our facilities. Compliance was required by early 2016.

III. WATER

A. Cooling Water Intake Structures

Section 316(b) of the federal Clean Water Act (CWA) requires the EPA to develop regulations governing the design, maintenance and operation of cooling water intake structures to assure that these structures reflect the best technology available for minimizing adverse impacts to aquatic species. The regulations must address both impingement (the trapping of aquatic biota against plant intake screens) and entrainment (the protection of small aquatic organisms that pass through the intake screens into the plant cooling systems).

[40] The CAA requires that EPA review standards such as MATS each eight years to determine if control technology has improved and if the residual emissions left after compliance with the MATS pose additional residual risk to the public. EPA recently proposed to find that, based on its review, no revisions to the MATS are required. 84 Fed. Reg. 2670 (Feb. 7, 2019).

The EPA released a 316(b) rule on May 19, 2014, along with a Biological Opinion issued by the U.S. Fish and Wildlife Service (FWS) and National Marine Fisheries Service (NMFS), and published the final rule in August 2014. The rule requires companies:

- To adopt one of seven options addressing impingement of biota at the entrance to cooling water intake structures, with approval by state or federal National Pollutant Discharge Elimination System (NPDES) permit writers;
- To minimize entrainment of biota into the structures, as directed by the permit writer taking a number of factors into account;
- To implement the impingement, entrainment, and other measures as soon as practicable after the entrainment measures have been identified, with interim milestones the permit writer may set, or for new units upon commencing operations;
- To provide extensive information in permit applications, including source water physical and biological data, intake structure and system data, proposed impingement compliance methods and supporting study plans, previously conducted entrainment studies, and the operational status of the plants; and
- For plants that withdraw more than 125 million gallons per day, to provide two-year comprehensive entrainment characterization studies, technical feasibility and cost evaluation studies, benefit valuation studies, and studies of non-water quality environmental and other impacts, with peer review of the last three.

The rule does not mandate the use of closed-cycle cooling for existing facilities. However qualifying closed-cycle systems will satisfy the final rule's impingement and likely will satisfy its entrainment requirements. The definition of qualified closed-cycle cooling has been broadened to include existing impoundments of waters of the U.S., if sufficiently documented as having been designed to provide a recirculating cooling function or if built in uplands, and to delete references to specific cycles of concentration, percentage flow reduction, and continuous flow constraints.

Regarding Endangered Species Act (ESA) provisions, the final rule requires permit writers to provide copies of applications to the FWS and NMFS, so these agencies can provide input within 60 days on endangered and threatened species and critical habitat potentially affected by intake structures and recommended permit conditions. If permit writers incorporate those conditions and permittees conduct all measures recommended by the Services, the permit will provide "incidental take" authorization. The FWS/NMFS biological opinion provided with the final rule states that the final rule is not likely to jeopardize listed species or destroy or adversely modify designated critical habitat.

The definition of "existing facilities" would include nuclear uprates and other repowered and significantly modified units, even if the turbine, condenser, or fuel are replaced. However, replacement units—essentially newly built, stand-alone units constructed at existing facilities regardless of change in generation capacity, cooling water flow, or use of an existing intake structure—would be considered a "new" unit and subject to closed-cycle cooling equivalent requirements.

The final rule provides a *de minimis* exception for impingement mortality requirements for very low impingement rates, but cautions that ESA-listed species may not be taken. The rule also provides less stringent impingement standards for low-capacity utilization units.

Upper Midwest system power plants that use greater than 2 million gallons per day of surface water are required to comply with the rule. This includes Sherco, Monticello, Riverside, High Bridge, Black Dog, King, Prairie Island, Red Wing, Wilmarth, Bay Front and French Island. Additionally, three plants may be required to reduce entrainment mortality: Monticello, King and Black Dog. The Sherco plant is already a closed-cycle cooling facility and as such, will not likely be required to make significant cooling water intake structure upgrades to comply with the rule.

B. Thermal Discharge

The EPA regulates the impacts of heated cooling water discharge from power plants under CWA Section 316(a). States with authority to implement and enforce CWA programs (e.g. Minnesota, Wisconsin) have state-specific water quality criteria including thermal discharge temperature parameters to protect aquatic biota. Plants must operate in compliance with the thermal discharge temperature parameters. No changes have been made to the thermal discharge temperature parameters in Minnesota. In 2010, Wisconsin implemented new water quality standards regulating the thermal discharge temperature from facilities with state-issued NPDES permits. The new requirements are being incorporated into facility permits as the permits come due for renewal.

Our Bay Front plant in northern Wisconsin was the first Xcel Energy plant to receive new thermal discharge limits, in 2012. Preliminary modeling of the plant discharge indicated that there could challenges to meeting the new requirements. Field monitoring of the discharge showed that the plant was complying with the new thermal discharge limits during normal operations.

French Island does not currently have to comply with the thermal rules. Preliminary evaluation indicates that French Island will have challenges to achieve compliance during the late summer and early fall periods of the year. The existing permit issued in 2018 requires a thermal monitoring plan (due 2020) with monitoring (due 2021). Monitoring data are due with permit application submittal (September 2022). Negotiations with the Wisconsin Department of Natural Resources during permit reissuance will determine what, if any, thermal limits are required.

C. Effluent Limitation Guidelines

As part of the NPDES process, the EPA identifies technology-based contaminant reduction requirements called Effluent Limitation Guidelines (ELGs). The ELGs are used by permit writers as the maximum amount of a pollutant that may be discharged to a water body and apply to power plants that use coal, natural gas, oil or nuclear materials as fuel and discharge treated effluent to surface waters, as well as to utility-owned landfills that receive coal combustion residuals. ELGs are periodically updated to reflect improvements in pollution control and reduction technologies.

The EPA revised the ELG rule on September 30, 2015 with two implementation deadlines. Impacted facilities are required to comply with the new requirements between 2018 and 2023. September 2017, EPA issued a rule postponing certain compliance dates of the 2015 ELG rule while EPA reconsiders portions of the rule. Specifically, EPA delayed the "no earlier than" compliance date so that facilities could not be compelled to comply with rule. EPA plans to issue a revised rule before the 2023 compliance due date and may propose a new compliance timeline.

EPA's 2015 final rule updated the ELGs for flue gas desulfurization systems (FGD), bottom ash transport water (BATW), flue gas mercury control systems (FGMC) and fly ash transport water (FATW) that discharge to surface waters. The final rule addressed discharges directly to surface waters and indirectly to surface waters via municipal wastewater treatment plants. The 2015 rule imposed prohibitions on discharging FATW and BATW either directly or indirectly to surface waters. The rule reduced the levels of contaminants allowed in FGD wastewater discharges. The changes were based on a technology evaluation conducted by EPA. The 2015 final rule had limited impact on our Upper Midwest power plants, with only one unit, the Allen S. King plant, being required to make capital improvements to address the prohibition on discharging BATW. King is studying options for converting the bottom ash system to a dry handled or fully recycled system. The Sherburne County plant is unaffected until the all coal units are retired at which time there may be residual water in the scrubber solids ponds that may need to be managed onsite without directly or indirectly discharging the wastewater.

D. Waters of the United States

In 2015, the EPA and the U.S. Army Corps of Engineers (USACE) issued a rule revising the regulatory definition of "waters of the United States" (WOTUS). The rule significantly expanded the universe of land features and water bodies that are subject to CWA jurisdiction. Under the CWA, federal permitting and oversight are required for any activity having the potential to impact WOTUS. Multiple suits were filed against the rule resulting in the 2015 rule being stayed in 28 states, but not in Minnesota. In February 2019, EPA and USACE issued a proposed rule that would revise the 2015 rule.

Our review of the EPA's 2015 final rule indicates that the new definition would impact the Company in a number of ways by adding complexity, cost and delay to project permitting. Current operations would also be impacted by the imposition of new regulatory requirements to previously exempt on-site or adjacent water bodies or ditches. We expect the rule would:

- Increase the difficulty of siting some projects, since many more areas will need to be avoided or be subjected to extensive and time-consuming CWA permitting;
- Complicate certain distribution line routing/re-routing work by triggering a lengthy permitting process before work can be conducted in or near WOTUS – for example, when the Company is required to reroute our lines due to state and local highway projects;
- Complicate the process to site, permit and construct wind and solar facilities, particularly in areas that have isolated water features. Additional time and cost will be incurred to either obtain the permits or to avoid areas that would trigger the need for federal permitting; and
- Increase cost and potential reliability issues as existing facilities, especially substations, must be retrofitted with additional oil-spill prevention and containment features to prevent an oil release from reaching WOTUS.

We are still evaluating the February 2019 proposed rule, but it appears to improve the clarity of the WOTUS definition, making it easier to define what water features will require federal permitting. Our analysis is not yet complete. EPA expects to finalize the proposed rule in 2020.

IV. COAL COMBUSTION RESIDUALS (ASH)

Coal Combustion Residuals (CCRs), often referred to as coal ash, is residue from the combustion of coal in power plants. Two common types of CCRs are fly ash and bottom ash. Fly Ash is a light material with the consistency of talcum powder that is carried from the boiler with the flue gas. This material is captured by pollution control equipment and may be combined with solids generated from air quality control systems designed to reduce SO_x and NO_x emissions. Bottom ash consists of the heavier materials collected from the bottom of the boiler. CCRs are either recycled for beneficial reuse or disposed of appropriately as non-hazardous industrial waste.

Currently the CCRs resulting from the coal combustion at Sherco Units 1 and 2 are disposed of wet within a permitted, engineered, lined surface impoundment as a non-hazardous industrial waste. The fly ash generated from Sherco Unit 3 is disposed of within a permitted, engineered, lined ash landfill located on plant property. The bottom ash generated from all Sherco units is stored within a lined impoundment as a non-hazardous waste until it can be beneficially used as a construction material or properly disposed on site.

The fly ash from the A. S. King plant is transported for disposal at a permitted, engineered, lined commercial landfill as a non-hazardous industrial waste, while the bottom ash from this facility is beneficially utilized in the manufacture of products. Xcel Energy's operations are subject to federal and state laws that impose requirements for handling, storage, treatment and disposal of wastes. These laws regulate CCRs as a non-hazardous waste under Subtitle D of the RCRA. While Xcel Energy's NSP-Minnesota disposal and storage facilities have been regulated by the Minnesota Pollution Control Agency (PCA) for several decades, they have only recently become subject to regulation under EPA's new CCR Rule.

EPA's CCR Rule became effective on October 19, 2015. This rule was promulgated in response to environmental concerns regarding structural failures and releases of ash directly to the environment from large surface impoundments (e.g. the 2008 Tennessee Valley Authority Kingston ash Impoundment failure and the 2014 release from Duke's Dan River Plant), allegations of inconsistent oversight by the states, and the potential for releases from unlined ash impoundments and landfills to impact drinking water sources.

The CCR rule establishes minimum design and operating requirements for CCR landfills and surface impoundments that are comparable to Minnesota's current requirements under State rules, site-specific permits and operating plans, with specific differences discussed in subsequent paragraphs. Under this rule regulated landfills and surface impoundments are referred to as CCR Units.

The CCR Rule requires ongoing ground water monitoring of each regulated CCR Unit. The rule also defines groundwater protection standards which if exceeded may lead to corrective action. Currently the results from the CCR Rule ground water monitoring program have shown no exceedances of CCR ground water protection standards (GWPS), meaning that no corrective action is required at this time.
The CCR Rule liner performance criteria are different than that established under the PCA's state program. As a consequence the Sherco Bottom Ash clay lined impoundment, is deemed lined under the state rule but is deemed unlined under the CCR Rule. Consequently Xcel Energy is in the process of replacing this impoundment with a new, lined impoundment that meets EPA and PCA requirements. Xcel Energy had previously anticipated the need to replace this impoundment and had plans to replace it by 2023. In order to comply with EPA's CCR Rule requirements Xcel Energy accelerated this project to have the new lined bottom ash impoundment available for use by October 31, 2020. Closure of the existing bottom ash impoundment is scheduled to be completed as originally planned in 2025.

Coal operations ceased at the Black Dog site in April 2015. CCR discharges to the three small impoundments present at the site ceased prior to October 19, 2015. These impoundments were closed by removal on December 12, 2016. The CCR materials removed from the impoundments were disposed of in an off-site, lined landfill. The CCR rule requires the completion of groundwater monitoring at closed CCR sites. Groundwater sampling under the detection monitoring program for this site has commenced and a determination as to whether there is a statistically significant increase (SSI) of groundwater constituents over background concentrations for Black Dog Impoundments 1-3 is due by April 17, 2019.